Independent Market Operator

Wholesale Electricity Market
Rule Change Proposal Submission Form

RC_2011_25 & RC_2011_37 Capacity Credit Allocation to Intermittent Generators

Submitted by

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Submission

1. Please provide your views on the proposal, including any objections or suggested revisions.

In the interests of bringing this long running issue to a close, APA is prepared to support the "modified" RC_2011_25 as proposed by the IMO Board and based on the Sapere methodology, subject to the following modifications:

1. The top 12 intervals per year based on LSG are replaced with the top 12 intervals per year based on demand; and
2. The U-factor is removed.

Absent these modifications, APA does not support the modified RC_2011_25, and recommends the IMO Board reject modified RC_2011_25 in favour of RC_2011_37; or alternatively, reject both rule changes completely.

The reason that APA does *not* supporting modified RC_2011_25 *without* the modifications is that it is our belief that intermittent generators provide far greater capacity value than can be measured simply in the top 12 intervals per year. We would prefer to see a larger number of intervals used in determining peak output. However, if modified RC_2011_25 is going to use only the top 12 intervals in each year, then it needs to address both the inconsistency of principle and the volatility this introduces due to using the LSG concept; as well as the manifest discrimination introduced by the U-factor.

The LSG concept

APA does not support the LSG methodology. It is inconsistent with the treatment of other generation capacity under the Market Rules[1]. It is also inconsistent with the rationale used in the Sapere methodology itself. A key aspect of the Sapere approach is to only use the very peak intervals of each year (super-peaks), based on the notion that the SWIS is a summer peaking market and that loss of load probability is based on a 1-in-10 year worst case summer peak. This diverges somewhat from previous approaches where 250 intervals (RC_2011_25) and 750 intervals (RC_2011_37) were proposed. The rationale for using only the top 12 intervals is that it tests the output of an Intermittent Generation Facility (IGF) when demand is greatest (and the IGF is most required). However, LSG has the potential to shift the top 12 intervals by demand into intervals that are not the super-peak intervals in a year[2]. If this is considered beneficial (i.e. it is argued that capacity is more valued during intervals where LSG is highest, rather than the premise of the SWIS being a summer peaking market and the loss of load probability is based on a 1-in-10 year worst case summer peak), then it would follow that other non super-peak intervals should also be considered; or that many more than 12 peak intervals should be used (a point argued in RC_2011_37). In fact, a more useful definition of an LSG super-peak would be not when scheduled generation is at its highest, but when the available capacity cushion is at its lowest. Scheduled generation is likely to be highest in summer peaks. DSM, for which the market is not in short supply, is specifically held aside by System Management for occasions when scheduled generation is not available. So at times of high LSG it is likely that there is also a high capacity cushion. However in shoulder periods, when much of the scheduled generation in the market is undergoing planned outage, and when DSM may have already been utilised during the summer peaks, there may be a stronger case to value output from IGFs when a relatively modest demand may put system security at risk.

To summarise, the LSG concept is inconsistent with using a small number of super-peak intervals to determine IGF capacity value. LSG should either be used with many more intervals, or should be abandoned if using a small number of peak demand intervals.

However the greatest problem with using the LSG concept in the modified RC_2011_25 methodology is that, by using only a small number of intervals for each year over 5 years, a new entrant IGF, by imposing its "estimated" output over the hot season of the last 5 years, is likely to alter the LSG intervals used. In fact, one would expect that a large wind or solar PV facility would be almost certain to do so. This introduces a level of volatility into the market that is neither welcome nor necessary. Preliminary analysis suggests that very small changes to the 60 intervals used for calculating the capacity for an individual IGF can lead to relatively large changes in the capacity value for the facility. A new investor will have problems financing a development if there is a risk of large fluctuations in revenue from year to year[3]. Using 12 *peak demand* intervals in each year over a 5 year period makes much more sense. Peak demand intervals are set. The historical peak cannot change with the introduction of new facilities. Each year, the last 12 intervals (of the earliest year) drop away

[1] Scheduled generators have their capacity allocated based on their output at 41 degrees, not what other scheduled generators are doing.

[2] Paradoxically, it does this due to the high output of IGFs during peak demand periods.

[3] Or the volatility will lead to a discount of possible revenue and hence higher prices.

and 12 new intervals (of the most recent year) are added. This is a low volatility method based on using only a small number of super-peak intervals.

To summarise, if it is deemed appropriate to use only a small number of intervals each year to calculate the capacity value of IGFs, then using peak demand intervals creates far less volatility than using LSG intervals.

<u>The U-factor</u>

As explained at the Sapere workshop, the U-factor is an adjunct to the core methodology, designed to negatively bias the output of the core methodology due to the unknown output of an IGF in a 1-in-10 year hot season. It is admittedly based on a mixture of statistics and 'gut feel'. APA is adamant in its position that the U-factor is inappropriate and should be removed from the methodology.

The core of the Sapere methodology is based on international practice, though admittedly, in jurisdictions where the correlation between load and intermittent resource (sun and wind) is not as strongly positive as it is in the SWIS. The U-factor is not. Nor is the statistics and 'gut-feel' used to determine the U-factor based on the 12 peak demand (or LSG) periods that is central to the core methodology. They are based on temperature. While there is a correlation between temperature and demand in the SWIS, there are many factors that make the relationship prone to error. A hot Sunday afternoon will not produce a peak demand day. A 40 degree day in Geraldton may correspond to a 25 degree day in Albany; just as a 40 degree day with strong easterly winds in Merredin may correspond to a 30 degree day with light sea breezes near the Midwest coast. If only 12 specific intervals are to be used each year, as is contemplated by modified RC_2011_25, then this level of inaccuracy is inappropriate. A U-factor is better suited to a much larger number of intervals. Additionally, as was also made clear in the workshop, when a 1-in-10 year hot season is encountered, then the U-factor becomes redundant. The fact is, in a 1-in-10 year hot season, just as in any other hot season, if an IGF is not producing in the peak intervals, then the number of capacity credits it receives will be commensurately reduced. To embed the U-Factor in the methodology would be either a double discount (if the IGF had low output in a 1-in-10 year hot season) or an unnecessary discount (if the IGF showed it was capable of high output in a 1-in-10 year hot season). The U-factor also uses a probability of exceedance based on the 95^{th} percentile. The market itself bases its probability of lost load on a 1-in-10 year assessment. Additionally, the modified RC_2011_25 uses 5 years' worth of peak interval data (rather than 10 years – consistent with a 1-in-10 year assessment, or 20 years – consistent with the 95^{th} percentile assessment). The U-factor is an inconsistent and unnecessary measure.

By far the largest problem with the U-factor however is its manifest discrimination against solar facilities, and a likely discrimination against wave and between individual wind farms. The U-Factor was specifically based on the assumed probability that wind farm output would be lower during periods of very high temperature (notwithstanding the issue of whether the ambient temperature at one particular wind farm had much relevance to the temperature at another; or to the temperature of major load centres – a discrimination between individual wind farm facilities). Logic dictates that the output of a solar facility would be at its greatest during periods of very high temperature. A solar facility should in fact have a positive U-factor. To *discount* the capacity output of a solar facility based on its assumed output during times of extreme temperature is nonsensical and clearly discriminates against that technology. It is unclear whether wave resources are in any way correlated to temperature. Based on this issue alone, it would be inappropriate to include the U-factor in the modified RC_2011_25 methodology.

Implementation of modified RC_2011_25

The issue, arising late in the second submission process, relating to the provision of data by Collgar and the inability of the IMO to use this data in the analysis of peak trading intervals, raises some questions over the implementation of the modified RC_2011_25. Currently, new entrant IGFs are able to provide evidence from an accredited consultant as to their expected average capacity factors over a three year period. This is a fairly easy analysis. New entrant IGFs will typically have many years' worth of detailed data (wind, wave or solar radiation measurements) which is used in the development and financing process. A reputable consultant will be likely to be willing to provide an accurate assessment of average output. However, providing an accurate assessment on the output of a facility based on 12 intervals (6 hours) in a year may not be so straight forward. APA suggests that the IMO discuss this issue with its list of accredited consultants to ensure that modified RC_2011_25, or any methodology using only a small number of intervals, is capable of being implemented for new entrant IGFs (including wind, solar and wave technologies)[4].

2. Please provide an assessment whether the change will better facilitate the achievement of the Market Objectives.

a) to promote the economically efficient, safe and reliable production and supply of electricity and electricity related services in the South West interconnected system;

It is arguable whether using only the top 12 intervals promotes better reliability, given our market holds over large quantities of DSM for such intervals, providing a large capacity cushion in peak periods. Using more peak intervals may have the benefit of spreading reliability over a greater period – though given how IGFs operate in reality, the difference is likely to be marginal.

Economic efficiency on the other hand is lowered by potential volatility introduced by new entrant IGFs under the LSG concept. A developer and financier will discount volatile capacity revenue and hence higher prices will be required to meet benchmark returns. These would be passed onto consumers. Removing the LSG greatly reduces the volatility, though 12 intervals will always be more volatile than 750.

(b) to encourage competition among generators and retailers in the South West interconnected system, including by facilitating efficient entry of new competitors;

[4] Preliminary discussion held between APA and an IMO accredited consultant suggests that this may prove to be difficult to implement under s similar Procedure to the current one.

Lowering volatility (and risk) will better facilitate new entrant generation.

(c) to avoid discrimination in that market against particular energy options and technologies, including sustainable energy options and technologies such as those that make use of renewable resources or that reduce overall greenhouse gas emissions;

Clearly, the U-factor is a manifest discrimination against solar facilities and a likely discrimination against wave facilities. It is also likely to discriminate between wind farms located in different climatic zones in the SWIS. Based on this alone, the U-factor cannot be included in any methodology.

(d) to minimise the long-term cost of electricity supplied to customers from the South West interconnected system; and

Reducing capacity credits to wind farms will increase the cost of energy and ultimately lead to higher costs to consumers. Increasing the capacity value for solar facilities will do the opposite.

(e) to encourage the taking of measures to manage the amount of electricity used and when it is used.

Actually increasing the level of generation that produces output with low or negative (with RECs) SRMC during peak periods will send inappropriate price signals to users of electricity. It is a supply side measure to the problem, rather than a demand side management. The impact of rooftop solar PV on household energy consumption is an example of this.

3. Please indicate if the proposed change will have any implications for your organisation (for example changes to your IT or business systems) and any costs involved in implementing these changes.

Any change to the capacity credit allocation methodology will have some impact on APA – as both an owner of an existing wind farm, and a developer of IGFs.

It is expected that the introduction of modified RC_2011_25 will result in a large decrease in the value of the Emu Downs Wind Farm. It would also increase the risk profile of the Badgingarra Wind Farm development project, make it less competitive with APA development projects in other jurisdictions and hence less likely to progress.

It is expected that the introduction of modified RC_2011_25 (with the amendments proposed in this submission) will result in a modest decrease in the value of the Emu Downs Wind Farm. It would also present a small increase the risk profile of the Badgingarra Wind Farm development project.

It is expected that the introduction of RC_2011_37, while increasing revenue risk, would have little impact on the value of the Emu Downs Wind Farm or the development of the Badgingarra Wind Farm project.

4. Please indicate the time required for your organisation to implement the change, should it be accepted as proposed.

NA